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Interest Rates and Price-Setting Practices in Canadian Electric and Natural Gas Utilities

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INTEREST RATES AND PRICE-SETTING PRACTICES IN CANADIAN ELECTRIC AND NATURAL GAS UTILITIES

Introduction

It is well known that energy-related utilities are capital intensive regulated monopolies. The large capital input leads to the presumption that the element of cost represented by the return on capital necessarily bulks larger in their total cost. Indication that the presumption is true for Canadian utilities is shown in the following table.

Costs as a Percentage of Revenues: 1980*

	Total industries	Total manufacturing	Gas distribution	Electric power
Operating expenses	79	87	78	45
Taxation costs	4	4	4	2
Capital costs	17	9	18	53

* Statistics Canada, 61-207, 1980.

Also, if regulatory authorities take cost as their standard for the revenue requirements of those utilities, capital costs will be an important component of their rate levels. Accordingly, the main purpose of this note is to describe the ways interest rate changes feed directly through into costs, and how those cost variations may affect electricity and natural gas prices. To do this, we looked at the various mechanisms used by provincial governments to regulate rates of gas and electricity distributors as well as how the National Energy Board sets tolls charged by gas pipelines.

This note is divided into three sections: electric utilities, gas distributors and gas transporters. For each section, we describe the current ownership structure of those energy-related utilities, how they are regulated (general procedure used as well as particular cases) and through which channels interest rate variations will affect their total costs. Also, for each subgroup of utilities (publicly owned natural gas distributors for example), we tried to get rough estimates of the direct impact of a one percentage point change in interest rates on their revenue requirements. The conclusion summarizes our findings.

This paper is one of the series of working papers for "Price Flexibility and Business Cycle Fluctuations in Canada - A Survey", a study prepared by the Research Department of the Bank of Canada for the Royal Commission on the Economic Union and Development Prospects for Canada. These research papers were all completed in early 1984.

I ELECTRIC UTILITIES

1 Background on Electric Power Utilities in Canada

1.1 Structure of the electricity supply in Canada

In 1982, 90% of electric energy generated was supplied by investor-owned and public utilities, whereas 10% was supplied by industrial establishments. Almost 68% of total generation comes from hydro, 10% from nuclear and 22% from conventional thermal. More than 77% of conventional thermal generation was produced from coal as the fuel. In total, only 5% of total electric energy production was generated from oil products or natural gas.

1.2 Capital investment

Electric utility capital investment as a percentage of GNP averaged 1.9% over the period 1966-70, 2% during 1971-75 and 2.4% over 1976-79. This fell to 2.2% in 1981, increasing to 2.5% in 1982. It is expected that this ratio will be reduced to around 1.5% over the period 1983-88.

1.3 Financial structure

In 1971, debt represented 76% of the capitalization of electric utilities in Canada. Debt, as a percentage of total capitalization, reached a maximum of 80% in the years 1977-1978, declining to 77% in 1981. As well, in 1980 for example, 30% of capital expenditures were financed through internally generated funds. Further, debt of publicly owned utilities is guaranteed by the province in which the utilities are located. As a result debt/equity ratios are much higher in publicly owned utilities than in investor-owned ones. In 1982 for example, debt financing of electrical utilities was 87% of capitalization in publicly owned compared to 48% in investor-owned utilities. [1] Total debt of electric utilities in 1981 amounts to $48.5 billion for total assets of $63.0 billion.

1.4 Ownership structure of the electric power industry and the regulatory body by province

Prince Edward Island and Alberta excepted, most of the electric utilities in each province are publicly owned. In Newfoundland, one investor-owned utility distributes around 85% of the electricity used in the province but almost all of the electricity sold is bought from the

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1. Within the publicly owned distributors, the variance is not negligible. Back-of-the-envelope calculations show that while debt as a percentage of total capitalization was 74.3% for Hydro-Québec in 1980, it was 93.6% for Manitoba Hydro, 85.2% for B.C. Hydro and 84.6% for Ontario Hydro. Calgary Power, an investor-owned utility showed 40.3% for 1980.

publicly owned Newfoundland Hydro. In Alberta, two investor-owned utilities supply 80% of total provincial supply. The remainder is sold through municipally owned utilities. In the Yukon and Northwest Territories, the federally owned Northern Canada Power Commission generates and distributes most of the electricity consumed. In all provinces but Newfoundland and Ontario, most of the electricity is distributed to consumers by the major producers. In Ontario, 321 municipal utilities (also publicly owned) distribute a large proportion of Ontario's consumption. The following table summarizes the industry ownership structure by province and indicates if rates have to be approved and if so, by whom.

Ownership of Canadian Electric Power Industry* and Rate Approval

Province	Ownership	Rates set by	Need for approval	Public hearings
Newfoundland	Public	Board of Commissions of Public Utilities	Cabinet	Yes
P.E.I.	Investors	Public Utilities Commission	No	Yes
Nova Scotia	Public	Public Utilities Commission	No	Yes
New Brunswick	Public	Utility	No	No
Québec	Public	Utility	Lieutenant Governor-in-council	Yes
Ontario	Public	Utility	No	Yes
Manitoba	Public	Utility	Lieutenant Governor-in-council	Yes
Saskatchewan	Public	Public Utilities Review Commission	No	Yes
Alberta	Investors	Public Utilities Board	No	Yes
British Columbia	Public	British Columbia Utilities Commission	No	Yes
Yukon and N.W.T.	Public	Public Utilities Board	No	?

* Major electric utilities in each province.

2 Rate-Setting in Publicly Owned Electric Utilities and the Role of Interest Rates

2.1 General procedure [2]

The desired revenue requirement is the starting point of the rate-setting process for publicly owned electric utilities. Essentially, the revenue requirement equation can be written as

$$R = RE + C + d + I + i\ D_N + T$$

where

R = the revenue requirement,
RE = the retained earnings,
C = the operating expenses,
d = the depreciation of current assets,
I = the interest payments on existing debt,
i = nominal interest rate on new debt,
D_N = the new debt, and
T = other expenses (such as taxes).

The interesting question is related to the problem of determining the margin for profit, the retained earnings. This variable is usually obtained from a set of financial criteria applicable to provincial electric utilities. As we will see in the next section, these financial criteria are, for most utilities, targets rather than regulatory statutes. For publicly owned utilities, the financial targets are

(i) Rate of return on equity

$$(RE/E) \geq \beta$$

where E is the equity at the start of the period and β is a positive constant;

(ii) Interest-coverage ratio

$$((R-C-d-T)/(I+i\ D_N)) \geq \alpha$$

where α is a positive constant (usually larger than one);

(iii) Debt/equity relationship

$$((E + RE)/(E+RE+D+D_N)) \geq \gamma$$

where D is the total long- and short-term debt at the beginning of the period minus the repurchased debt during the regulatory period and γ is between zero and one.

A given utility may have to satisfy one, two or all three financial criteria. For instance, according to its statutes, Hydro-Québec should maintain an interest-coverage ratio not less than one and a debt/equity

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2. This section draws on Berkowitz and Halpin (1981) as well as on J.T. Bernard (1983).

relationship equal to .25. Although the return on equity is not mentioned in its statutes, the company's stated target is to have a return of not less than the average interest rate paid on the debt. When more than one of these criteria are relevant, the constraint that yields the highest revenue requirements will also satisfy the other constraints.

After the revenue requirement has been determined, the amount to be collected from domestic consumers is calculated by simply deducting other sources of revenue (such as export sales) from the total revenue required. If no other factors have to be examined, then the average price increase will be set such that revenues collected from domestic sales just equal the required revenue.

When the financial criteria are very specific and required by the statutes of the publicly owned utility and/or the body regulating the utility, the determination of the revenue requirement is necessary to set the desired average rate increase. It gives the minimum rate increase the utility will obtain. On the other hand, when the financial criteria are simply targets set by either the regulatory body or the utility, they are of little help in predicting the average rate increase. Each utility has distinctive characteristics, meaning that any given set of financial criteria has very different implications for different utilities.[3, 4] Since it reflects the costs of service (which cannot be neglected indefinitely), the revenue requirement is an important input in helping to determine rates. However other factors are also considered and for a given period of time, those factors might be important enough to dominate financial markets criteria.

For a given volume of sales, interest rate changes will affect revenue requirements (and eventually rates) through the impact on the nominal interest coupon on new debt, and the interest to be paid on old debt financed at variable rates. Also, the rate of return on equity is likely to fluctuate with the current interest rate and if there is a specific target for the rate of return on equity, the revenue requirement will also be directly affected. If changes in the cost of capital are fully passed into rates and if the elasticity of demand is not zero such that sales are affected (or expected to be affected), then a rise in interest rates will increase the amount of debt required[5] and consequently, the revenue requirement. If real interest rates are changed (or perceived to be changed), the structure of the production technology

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3. The usual argument for financial criteria is that, without them, the unit cost of debt will increase, eventually to infinity.

4. The level of rates, the expansion program, the structure of the generating capacity (hydro or thermal), the ultimate borrower (some provinces borrow directly for their utility and do not simply guarantee their debt) and the financial health of the home province are some factors to be considered aside from financial criteria.

5. Investment programs are not easily changed (the "short run" is easily 5 years) to reflect reductions in demand.

may also be changed. The term structure of the debt will also react to significant changes in interest rates. For instance, the high rates of interest experienced during the last three years have generally led to significant reductions in the average term to maturity of the debt and in a larger share of variable-rate debt.

Rates are usually revised every year and are based on the expected values of sales, interest rates, exchange rates and cost inflation during the year the revised rates will apply. Any gap between expected and realized values will result in some sort of disequilibrium and will affect rate changes in following years.

In order to get a rough idea of the potential impact of a change in interest rates on revenue requirements of publicly owned utilities, we have done the following simple calculations. Total long-term debt of publicly owned electric utilities in Canada was $42 billion in 1981. It is assumed that the portion of the debt due within the following year is constant and that the total debt will be refinanced over the next 20 years. We also assume that 75% of the investment expenditures planned by publicly owned electrical utilities will be financed by issuing new long-term debt. A permanent increase of one percentage point in the interest rate might increase interest payments by the following amounts:

Impact of a One Percentage Point Increase in Interest Rates on Interest Payments of Publicly Owned Canadian Electric Power Utilities*

	Increase in interest payments ($ million)	Sales (billions of kwh)	Increase in average price (cents/kwh)	Average price (cents/kwh)
1982	77	345	.022	2.7
1983	162	362	.045	3.0
1984	236	379	.062	N/A
1985	301	401	.075	N/A
1986	362	415	.087	N/A
1987	428	430	.100	N/A
1988	501	445	.110	N/A
1989	582	460	.127	N/A
1990	678	475	.143	N/A

* All numbers are in current dollars.

This table shows that a one percentage point increase in the average nominal interest rate on public utility debt will increase nominal revenue requirements by $77 million in the first year. If the duration of the interest rate shock is only one year, then the $77 million will be required for the years to maturity of the bonds. If the shock is a permanent rise in interest rates, revenue requirements will increase as new investments incur new debt and the old debt is refinanced. To suggest the potential impact on rates for electricity, we have calculated the yearly average price increase necessary to raise those revenues.

Nominal long-term bond yields are much higher today than was the case 20 years ago. For instance, the average interest on public utility new long-term debt was around 6% in 1961 and 17% in mid-1981. Refinancing old debt and financing new investment expenditures at today's rate of interest certainly contribute to the explanation of rises in electricity rates. In 1980, new debt of electrical utilities in Canada represented around $3.5 billion whereas total operating expenses were around $5.8 billion. Those numbers show that the cost of capital is an important item in the total costs of electrical utilities.

The indirect impact of high rates of interest on electricity prices may be larger than the direct impact in the short run. For instance, the response of real economic activity to high real rates of interest will affect sales of electricity. Given the large share of hydro and nuclear generating capacity in Canada, operating costs will not be reduced significantly and since the capital expenses are fixed in the short period, revenue requirements will not show significant reduction, resulting in a larger average price.

2.2 Particular cases

2.2.1 Rate-setting at Hydro-Québec

Under the statutes of Bill 16, Hydro-Québec must satisfy one basic financial criterion. The interest coverage before any dividend is paid to the Minister of Finance must not be lower than one. This means that net income of the year must be at least as large as gross interest to be paid on debt, including interest during construction. Bill 16 also stipulates that no dividend will be paid to the Minister of Finance if the capitalization rate is lower than 25% which amounts to saying that the proportion of equity in total capital should not be less than 25%. Any net income left will then be paid as dividends to the Minister. As mentioned in the previous section, Hydro-Québec rates are set by the utility but approval by the provincial Cabinet is needed.

Thus far, it seems that the financial criteria were the main factors explaining the annual increases in Hydro-Québec's average rate. In fact, even before Bill 16 in 1981 (Hydro-Québec then had the mandate of selling at prices as low as the financial soundness of the enterprise would permit), Hydro-Québec was using the financial targets to set their prices. With decreasing investment expenditures and growing sales, it seems that restrained price increases will be sufficient to satisfy the financial requirements. As Hydro-Québec only has a limited incentive to increase its dividend payments to the Minister and would rather like to sell more of its product, the company wants to keep its rates as low as possible. Thus, their program is to increase prices in such a way that they almost exactly satisfy the more restrictive financial target, the 25% capitalization rate. The following table presents those numbers.

Financial Ratios and Rate Increases for Hydro-Québec*

	Sales (TWH)	Increase in CPI (%)	Average interest rate on debt (%)	Average rate increase (%)	Interest coverage	Capitalization rate (%)	Return on equity (%)	Dividends paid ($ million)
1981	106.9	12.5	15.1	10.6	1.01	25.1	12.0	7
1982	103.6	10.8	13.5	16.3	1.01	26.0	15.0	7
1983	106.0	5.9	11.5	7.3	1.01	26.6	11.2	35
1984	119.2	5.4	11.3	3.4	1.02	25.0	3.3	34
1985	130.0	7.0	12.0	5.4	1.11	25.0	4.3	0
1986	137.4	8.0	13.1	4.8	1.10	25.0	4.5	82

* Plan de développement d'Hydro-Québec, 1984-1986, September 1983.

For the years 1981 to 1983, the interest-coverage ratio was close to its required level and interest payments played the important role in rate-setting. As shown in the above table, in following years, the debt/equity relationship is expected to become the binding constraint although, since dividends are expected to be paid, desired rate increases could have been lower for the years 1984 and 1986. [6] This table shows eloquently that Hydro-Québec does not have to realize a specific rate of return on equity. As shown in the third and seventh columns, the mentioned target of achieving a rate of return on equity not less than the average rate paid on the debt is not having much weight in its current decisions about rate increases. As a matter of fact, for most publicly owned electric utilities, equity is practically a free good. According to Hydro-Québec, even zero nominal increases in electricity rates after 1986 will result in higher financial ratios than those required or suggested by Bill 16. If those projections are right, then "reasonable" variations in interest rates will have no impact on revenue requirements and therefore on electricity rates. The impact of various shocks on revenue requirements of Hydro-Québec for the year 1984 is reported below.

6. In fact, since the interest coverage is the only constraint required by Bill 16, rate increases anticipated by Hydro-Québec could have been lower than those reported here. This is the case even if the capitalization rate is maintained at its desired level of 25%. Lower rate increases for 1984 and 1986 would have cut the dividends without reducing the capitalization rate below 25%.

Impact of Changes in Various Parameters on Revenue Requirements of Hydro-Québec for the Year 1984*

Parameter	Shock	Increase in revenue requirements ($ million)
Sales	-1%	28.1
Rate of interest	+100 basis points	25.0
U.S.$/Cdn$	-1 cent	26.0
Operating expenses	+1%	12.0
Other expenses (depreciation, taxes and electricity bought)	+1%	7.1

* Rate of interest shock assumes that all new debt is financed at the beginning of the year. These numbers have been computed using data from the Plan de Développement d'Hydro-Québec.

At our request, the financial department of Hydro-Québec supplied us with a longer-run interest rate shock exercise. Their numbers show that a one percentage point increase in interest rates will reduce net income by some $500 million over the 1984-90 period. The dividends that will be paid to the Minister over the same period amount to some $400 million. This means that simply by cutting dividends, they would be able to meet 80% of the additional revenue requirement. So, if they want to maintain a capitalization rate of 25%,[7] they will have to generate an additional $100 million in sales over the next seven years, a very small amount.

The specific case of Hydro-Québec shows that although there is a direct link between interest rate variations and cost variations, it is not at all obvious that cost variations will be translated into proportional price changes in their products. In the coming years, price changes will be large enough to comply with the interest-coverage criterion, pay some dividends to the Minister of Finance and satisfy capital market requirements. On the other hand, they will be small enough not to worsen the relative price of electricity in markets where substitution to other energy sources is possible, and not to impose real price increases on captive markets.

2.2.2 Rate-setting at British Columbia Hydro

B.C. Hydro owns and operates an electric service that supplies power to approximately 90% of the people of British Columbia, and a gas distribution service that ranks, in terms of customers served, as the

7. This is not necessarily the case since their financing requirements would be much lower than they were in the past and, consequently, they might not necessitate a debt/equity ratio as low as they used to have.

third largest gas distribution utility in Canada. As indicated earlier, B.C. Hydro is regulated by the British Columbia Utilities Commission. Of special interest to us is the Special Direction addressed to the Commission regarding the regulation of B.C. Hydro. Among other things, B.C. Hydro had to generate adequate funds from the efficient operation of its business to support all of its activities and its debt. The utility had to achieve a financial position that allows it to borrow funds on the most economic terms available. B.C. Hydro also had to aim for an interest-coverage ratio of 1.3 times in fiscal 1984 and maintain that ratio thereafter so as to achieve and ultimately maintain a debt/equity ratio of 80/20.[8, 9] The February 28, 1983 Commission decision in the matter of B.C. Hydro applications was the result of the Commission's first review of B.C. Hydro's affairs. The Commission has been very critical of all aspects of B.C. Hydro's planning system. The following paragraphs show how the Commission regulating B.C. Hydro fulfils its role.

In its first application to the Commission, B.C. Hydro (electric power branch) requested increases of 11.15% effective August 1, 1981 and 11.66% effective April 1, 1982. On November 23, 1981, falling revenues forced B.C. Hydro to revise its original application of an 11.66% increase for April 1982. The utility wanted an increase of 17.85% to improve its interest coverage. On March 30, 1982, the Commission granted an interim increase of 11.5% effective April 1, 1982. The Commission's Order also provided for a 5% decrease in controllable expenditures in the expectation that this might enable the utility to reach its targeted interest-coverage. Again, falling revenues from sales of electricity forced B.C. Hydro to request on May 28, 1982 additional increases in electric rates of 7.7% effective April 1, 1982 (total of 19.2%) and 15.7% effective April 1, 1983.

The Commission concluded that the utility should achieve its financial goals first by increasing its operating efficiency, then by increasing its sales volume, and only in the last resort by increasing its rates. The interim increase granted on March 30, 1982 was confirmed by the Commission on February 28, 1983. For fiscal 1983, the interest-coverage ratio was estimated by the Commission at 1.11. The Commission has estimated that the rate increase necessary to reach the 1.3 interest-coverage target for fiscal 1984 would be 25% effective April 1,

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8. This is not necessarily the case since their financing requirements would be much lower than they were in the past and, consequently, they might not necessitate a debt/equity ratio as low as they used to have.

9. The Special Direction clauses are what have been added to the provisions of the Utilities Commission Act in the particular case of B.C. Hydro. It is worth noting that achieving an interest-coverage ratio of 1.3 by 1983-84 was among the objectives of the company in its 1982 Corporate Plan. It is made clear in the Decision of the Commission that the interest-coverage ratio of 1.3 (which has been endorsed by the Special Direction) is a <u>target</u> around which "achieved coverages could be expected to fluctuate to some degree".

1983.[10] The Rate Increase Restraint Act of the B.C. government set a limit of 6% on any increases and B.C. Hydro was therefore granted 6% on its rates for electric service.

The impact of various shocks on the revenue requirements of B.C. Hydro is reported below. We also computed the longer-term effect on revenue requirements of a permanent one percentage point increase in the interest rate. The revenue requirement is increased by about $11 million in 1983, $82.3 million in 1988 and $191.9 million in 1992.

Impact of Changes in Various Parameters on Revenue Requirements of B.C. Hydro for the Year 1983*

Parameter	Shock	Increase in revenue requirements ($ million)
Sales	-1%	11.6
Rate of interest	+100 basis points	10.9
U.S.$/Cdn$	-1 cent	5.0

* Rate of interest change assumes that all new debt is financed at the beginning of the year. Those numbers have been computed using data from the annual report of B.C. Hydro and the B.C. Utilities Commission's decision in the Matter of B.C. Hydro Applications for Rate Relief.

2.2.3 Rate-setting at Ontario Hydro

As indicated above, rates at Ontario Hydro are set by the utility's board of directors and there is no need for approval. However, under the provisions of the Ontario Energy Board Act, a public hearing before the Board is required in respect of any changes in electricity rates proposed by Ontario Hydro. The recommendations of the Board are submitted to the Minister of Energy. After considering the recommendations of the Board, Ontario Hydro's board of directors establishes the electricity rates to be charged to customers. The rates charged by Ontario Hydro are determined by forecasting revenue requirements of a test year period. They must cover the cost of service plus some margin consistent with "proper utility management" and/or "financial soundness".

As in the case of other publicly owned electric utilities, Ontario Hydro makes use of interest coverage and debt/equity ratios to characterize its financial soundness, although no specific values for those criteria are specified in the provisions of the law. Interest coverage was 1.3 times in 1981 and 1.2 times in 1982, while the

10. Had energy sales actually occurred as they were forecast in B.C. Hydro's Corporate Plan of March 1981, a rate increase of about 11% would then have been required.

capitalization rate was 15.9% in 1981 and 15.5% in 1982.[11] In its recommendations to the Minister (on the proposal of Ontario Hydro to increase rates on January 1, 1984), the OEB reported that Ontario Hydro, on input from the financial community, established (in 1976) a desired range of 18% to 20% for equity as a proportion of total capital and a target of 1.35 times for the interest-coverage ratio. It is noted by the OEB that while these "targets were considered in subsequent rate proposals they were never fully achieved because of the general economic climate and anti-inflation programs".[12]

The reference letter from the Minister of Energy to the Chairman of the OEB usually contained restrictions on borrowing by Ontario Hydro or stipulations as to the value of one or both of the financial criteria. In the past two years, no financial criteria have been stipulated by the reference letter to the OEB. However, the Treasurer of Ontario stated in a letter to the Chairman of Hydro that he "would be concerned if either Hydro's financial planning, or Ontario Energy Board recommendations, were to contemplate any trend toward a material deterioration in Hydro's debt to equity ratio or interest coverage performance". Ontario Hydro took the Treasurer's letter to reaffirm its approach to the determination of net income and, in order to improve the figures of 1982, asked for a net income of $404 million, corresponding to an overall average rate increase of 9.7%. On the other hand, the OEB considered that the financial criteria of 1982 were satisfactory, and that in order to achieve the same level of debt/equity, a net income of $350 million was necessary. The net income recommendation of the OEB, taken together with other adjustments recommended, would have produced an average rate increase in 1984 of 6.3%. The OEB criticized Ontario Hydro for having based its rate determination on cost recovery to the exclusion of marketing considerations (price elasticity of demand). The Board also pointed out that the fight against inflation was of such importance that Ontario Hydro should be striving for meaningful reductions in real tariffs during 1984 by cost avoidance and if need be, by lowering net income during 1984 to a level lower than that recommended earlier ($350 million). We now know that the utility has announced that it intends to impose a rate increase of 7.8% overall but it will retain the target of $404 million net income. Ontario Hydro will achieve that by implementing cost-cutting recommendations of the OEB. The utility also feels that the economy, which has strengthened since the original proposals were made, should help boost power sales somewhat.

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11. It may be noted that in the case of public borrowing in the United States, the Province of Ontario borrows on behalf of Hydro by issuing its own debentures and advancing the money to the utility.

12. Ontario Energy Board, Ontario Hydro Bulk Power Rates for 1984, Report to the Minister of Energy, August 31, 1983.

As the specific case of Ontario Hydro shows, a given revenue requirement (to improve financial criteria) can sometimes be achieved with a lower rate increase, by cutting controllable costs and/or improving the productivity of capital (increasing sales).

3 Rate-Setting in Investor-Owned Electric Power Utilities and the Role of Interest Rates

In 1981, sales of electricity by investor-owned electric power utilities represented around 7.5% of total sales of electric power utilities. Total assets of private electric power utilities were $3.9 billion in 1981.[13] Shareholders' equity amounted to $1.9 billion for a 50% share of total liabilities. Rate-setting in investor-owned electric utilities is based on the "cost of service" plus a margin for profit which is equivalent to specifying an allowed rate of return on equity capital. It is apparent from the previous section that the return on equity is not considered an important financial criterion by publicly owned utilities or their regulators. For investor-owned utilities however, this criterion is the single most-used measure of the profitability of the business. The main characteristics of the regulatory process of investor-owned utilities are presented in the following section on natural gas. No important distinction can be made between the regulatory procedures of electric and natural gas utilities; the difference is whether the utility is privately or publicly owned. Since almost all gas distributors are investor-owned, we prefer to describe the general procedure of regulation in the case of private utilities in the natural gas section.

We have performed an exercise similar to the one above for publicly owned electric utilities. This time, however, the return on equity has to be taken into account explicitly. The assumptions on the treatment of equity capital are the same as those of investor-owned natural gas utilities and are listed in the proper section below. The life of assets is assumed to be 40 years. Investment figures are those of utilities in Alberta and Prince Edward Island.

The table shows that the impact of interest rate changes is more important for privately owned electric utilities than publicly owned. Unlike investor-owned utilities, publicly owned utilities do not have to realize a rate of return equal to the opportunity cost of their equity capital.

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13. Total assets of publicly owned utilities were $59.2 billion in 1981 and equity represented 16.3% of total capital (Statistics Canada, 57-002, 1981).

Impact of a One Percentage Point Change in Interest Rate on Cost of Capital of Privately Owned Canadian Electric Utilities*

	Increase in cost of capital ($ million)	Sales (billions of kwh)	Increase in average price (cents/kwh)	Average price (cents/kwh)
1982	27	19.4	.139	2.7
1983	37	20.4	.181	3.0
1984	48	21.4	.224	N/A
1985	58	22.5	.258	N/A
1986	67	23.6	.284	N/A
1987	77	24.8	.310	N/A
1988	88	26.0	.338	N/A
1989	101	27.3	.370	N/A
1990	116	28.7	.404	N/A

* All numbers are in current dollars. We increased sales at 5% per year even though privately owned utilities expected (in 1981) sales to grow at 7%. We feel that the current outlook for the Alberta economy cannot lead to such large increases in sales.

II NATURAL GAS DISTRIBUTORS

1 Background on Natural Gas Distributors

1.1 Natural gas sales and capital investment

The share of natural gas in total primary energy consumption in Canada remained constant at about 18.5% over the 1972-81 period. In 1982, the share of natural gas jumped to 19.3% and is expected to reach about 22% in 1990. Domestic sales of natural gas by utilities amounted to 1,500 billion cubic feet (1.5 billion mcf) in 1982. Capital investment expenditures by natural gas utilities averaged $125 million (constant 1971 dollars) per year over the 1973-79 period. During the years 1980-82, investment expenditures increased to $165 million per year and we expect spending of $190 million per year over the period 1983-85. As long as the Maritimes and Vancouver Island extensions are not realized, the main source of net growth in the assets of the industry is the development of the distribution network in Québec.

1.2 Ownership structure of the natural gas distribution industry and the regulatory body by province

Most of the Canadian natural gas distribution industry is made up of investor-owned corporations. We estimate that in 1982 around 88% of domestic sales were realized by privately owned companies while the remaining 12% were made by publicly owned utilities. In Saskatchewan, the Saskatchewan Power Corporation, a wholly government-owned corporation, distributes virtually all gas sold in the province. In British Columbia,[14] British Columbia Hydro accounts for about 55% of the total

14. Serving the city of Vancouver, the Fraser Valley and Greater Victoria (propane-air gas).

sales in the province, the remainder being sold by privately owned suppliers. Notice that even though Soquip and the Caisse de dépot hold over 50% of shares of Gaz Métropolitain, we consider the corporation to be investor-owned. In the following table, we do not consider the small municipally owned distributors.

Ownership of Canadian Gas Distribution Industry* and Rate Approval

Province	Ownership	Rates set by	Need for approval	Public hearings
Québec	Investors	Régie de l'électricité et du gaz	No	Yes
Ontario	Investors	Ontario Energy Board	No	Yes
Manitoba	Investors	Public Utilities Board	No	Yes
Saskatchewan	Public	Public Utilities Review Commission	No	Yes
Alberta	Investors	Public Utilities Board	No	Yes
British Columbia	Public(1)	British Columbia Utilities Commission	No	Yes

* Major distributors in each province.
(1) Public 55%; investors 45%

1.3 Financial structure

As in the case of investor-owned electric utilities, investor-owned natural gas distributors show a debt/equity ratio much lower than publicly owned utilities. Over 1978-81 equity averaged 34.4% of the total capitalization of all natural gas utilities. The financial structure of investor-owned natural gas distributors, as for other private corporations, has been significantly affected by the recent recession. For the whole industry, the equity share went from 48.5% of total capitalization in 1980 to some 30.0% in 1981. The pattern is the same for the major utilities. For instance, Consumers' Gas (the largest utility in terms of sales) had a capitalization rate of around 60% during 1978-80. This rate fell to 27% in 1981 and 31% in 1982. For publicly owned natural gas distributors, equity represented 20.1% of capitalization in 1980 and

20.9% in 1981.[15] As in the case of publicly owned electric power utilities, debt is an important proportion of the capitalization of publicly owned natural gas utilities.

In the introductory table, we showed that the gas distribution industry was more "capitalized" than the manufacturing sector but not significantly more than Canadian industry overall. Operating costs represented 78% of total cost in 1980 (mainly gas purchased) whereas capital costs accounted for 18%. The remainder was composed of various payments to governments.

2 Rate-Setting in Investor-Owned Natural Gas Utilities and the Role of Interest Rates

2.1 General procedure

As for publicly owned utilities, the revenue requirement is the starting point in the rate-setting process of investor-owned natural gas utilities. In the case of investor-owned utilities, the revenue requirement equation can be written as follows

$$R = C + d + T + s\,B$$

where

R = the revenue requirement,
C = the operating expenses,
d = the depreciation of current assets,
T = other expenses,
B = the rate base, and
s = the allowed rate of return on the rate base, the cost of capital.

The overall rate level is determined by taking the total revenue requirement and dividing by the expected output. The rate base is defined as the average value of plant in service during a test period plus an allowance for working capital such as inventories. The rate of return on the rate base is simply the weighted average of the allowed rates of return on each capital component

$$s = (\beta E + i\,D_N + i^*D + pP)/V$$

where

β = cost of (common) equity capital,
i = nominal interest rate on new debt,
D_N = the new debt,
p = embedded cost of preferred shares,
P = book value of preferred shares,
E = book value of (common) equity,

15. Assets of publicly owned natural gas distributors (B.C. Hydro, Saskatchewan Power and municipal utilities) were $828 million in 1981, for a share of 15% of total assets of the industry (Statistics Canada, 55-005).

i^* = weighted average of the coupon rates on all outstanding debt,
D = total outstanding debt at the beginning of the period, and
$V = E + D + D_N + P$.

As in the case of publicly owned electric utilities, the cost of the outstanding debt is the average coupon rate to be paid. For preferred shares, the cost is calculated as a weighted average of the dividend yield (based on book values) on the outstanding issues. The cost of equity capital is based on the opportunity cost of those funds. For regulatory purposes, the only difference between investor-owned and publicly owned utilities is the importance given to retained earnings. We have seen that the rate of return on equity does not have a high rank in the financial criteria used to set the revenue requirements of publicly owned utilities. Even if economic efficiency would suggest that the opportunity cost of retained earnings should be taken into account, those funds being publicly owned, a lower than opportunity cost rate of return on equity would not be prejudicial to the utility. In the case of investor-owned utilities, however, a rate of return on equity smaller than expected (say, because the rate of interest on new debt was higher than anticipated by the regulatory body) will result in lower stock prices and may lead to financing problems. The rate of return on equity, β, will then play an important role in the determination of revenue requirements of privately owned utilities.

With very few exceptions related to technical questions, rates in the investor-owned sector are all regulated in the same way. Rates are supposed to generate sufficient revenues after all costs are paid (including the cost of capital) to guarantee the owners a granted return on their assets. A typical regulatory board proceeds on a prospective test year basis. Given a desired rate of return on equity, the utility will supply a forecast of its revenues and expenses within the test year assuming the current rate level and design. If a revenue deficiency is expected, the utility will request an increase in its rates. In all cases, the board will make some judgements as to the assumed level of sales, interest rates, inflation rate and so on.

The allowed rate of return on equity is usually based on the assumption that the cost of equity capital is equal to the risk-free interest rate plus a premium for the risk exposure of the equity investor. The investment risk is composed of the risk of the basic operations of the company (regulatory risk in the specific case of utilities) and the financial risk associated with the financing of the assets. Changes in either business or financial risk or the risk-free interest rate will result in changes in the cost of equity capital. In practice, this rate of return is based on the cost of capital of a number of other regulated utilities.

For a given volume of sales, interest rate changes will affect revenue requirements (and probably tariffs) through the impact on the nominal interest coupon on new debt (refinancing plus gross investment expenditures), the flexible rate debt and the cost of equity capital. Hence, while for publicly owned utilities the direct impact of interest rate changes is through the debt, for investor-owned utilities the cost of both debt and equity will be affected. To get a rough estimate of the potential impact of a change in the interest rate on revenue requirements of investor-owned natural gas distributors, we have undertaken the following calculations. As in the case of electric utilities, we assumed that the debt of private natural gas distributors in Canada ($2,613 million in 1980) will be refinanced over the next 20 years at the current rate of interest. Investment expenditures will be financed with a mixture of debt and equity. In the case of investor-owned utilities, we can assume that the result of an interest rate change will be independent of the debt/equity structure. Generally, the cost of both types of capital will go up by the given increase in the interest rate. The return on equity at the starting period will also be affected by interest rate changes. However, since we added gross investment expenditures to total assets, equity is reduced each year by the amount of depreciation (assumed to be over 25 years). A permanent increase of one percentage point in the interest rate might increase the cost of capital by the following amounts:

Impact of a One Percentage Point Increase in Interest Rate on the Cost of Capital of Investor-Owned Canadian Natural Gas Distributors*

	Increase in cost of capital ($ million)	Sales (millions of mcf)	Increase in average price ($/mcf)	Average price ($/mcf)
1981	29.8	1332	.022	3.08
1982	34.6	1364	.025	3.57
1983	39.4	1353	.029	3.95
1984	45.0	1521	.030	4.03
1985	51.4	1583	.032	4.18

* All numbers are in current dollars. Average price and investment figures are estimated from forecasts by the various utilities. Investment estimates are proportional to sales of investor-owned natural gas distributors.

As suggested before, the natural gas distributors are much less capitalized than electricity distributors and the impact of interest rate increases is also smaller as illustrated by this exercise. Again high interest rates may exert greater upward pressure on the revenue requirement indirectly through their impact on sales than they do directly through variations in costs.

2.2 Rate-setting at Consumers' Gas

On April 6, 1983, the Consumers' Gas Company Ltd applied to the Ontario Energy Board for an order approving just and reasonable rates for the sales of natural gas, with requested increases to become effective on October 1, 1983. The utility's final submission is summarized below:

Rate base ($ million)	1225.6
Operating and administrative costs ($ million)	1382.6
Cost of capital (%)	
Long-term debt ($595.2 million)	12.11
Unfunded debt ($23.4 million)	10.30
Preferred shares ($110.7 million)	11.07
Common equity ($448.4 million)	16.00
Requested return on rate base (%)	13.05
Gross revenue deficiency ($ million)	19.5

The utility proposed that the revenue deficiency of $19.5 million should be recovered through rate increases to all customers. The Ontario Energy Board (OEB) looked at each component of revenues and costs and for some items, ruled that revisions were necessary. For the long-term debt, the Board accepted an interest cost of 12.11% for the test year (fiscal 83-84 in our case). As for unfunded debt, given the expectations that short-term interest rates would trend downward and that the prime rate would average 10.5% over the test year, the OEB concluded that a cost allowance of 10% was reasonable. The utility requested a return on equity of 16% during the 1984 test year. The company relied upon the evidence presented by two witnesses (Nesbitt Thomson Bongard Inc. and Foster Associates Inc.) before the OEB. Three tests were used by the witnesses to arrive at this recommendation with respect to return on equity: the comparable earnings, the risk premium and the discounted cash flow.

The risk premium analysis depends upon a sampling of interest rates on government or corporate bonds, or on preferred shares over appropriate time periods which serve as bases to which risk premiums are added to arrive at a rate of return for equity holders. Depending on who did the risk premium analysis, the range of values for the cost of equity capital was 14.25% to 16.5%. The comparable earnings tests involve examination of earnings data for similar groups of companies considered to be comparable. Again, recommendations were within a range of 3 percentage points depending on the sample chosen and the span of years from which the data were drawn. The discounted cash flow method assumes that the investors' expected return on a common stock is the sum of the present expected dividend yields and the growth prospects for dividends or book value. The exercise is based on a sample of corporations related to the industry. The range this time was 13.2% to 15.5%. The Board placed greater emphasis on the comparable earnings test and the risk premium analysis. The OEB was also of the opinion that interest rate levels and

the rate of inflation will fall below the levels expected by some witnesses and found that a rate of return on common equity of 15.3% was appropriate. The overall cost of capital (properly weighted by the share of each source of funds) was therefore set at 12.8%. After all adjustments were made, the Board found that the expected net income (after taxes) of Consumers' Gas was $155.1 million, resulting in a rate of return of 12.8%. The Board concluded that there would be no revenue deficiency in the test year and so no rate increase was granted.

The statement of income of Consumers' Gas appropriate to their Ontario utility business shows that for the 1983-84 fiscal year, gas costs will represent 76.8% of revenues, other operations and maintenance costs 7.3%, 3.8% will be paid to governments and, finally, 12.1% will represent the cost of capital.

3 Rate-Setting in Publicly Owned Natural Gas Distributors

As mentioned above, British Columbia Hydro and Saskatchewan Power are the two main publicly owned gas distributors in Canada, and accounted for 12% of total domestic sales in 1982. Other publicly owned gas utilities are municipal corporations. The regulatory procedure of those public utilities is the same as the one described in the first section on publicly owned electric utilities. In the specific cases of B.C. Hydro and Saskatchewan Power, the gas services are treated separately from electricity services by the regulator. Financial targets such as the interest coverage and the debt/equity ratio are then used to determine retained earnings and revenue requirements. Proceeding as in the case of publicly owned electric utilities, the following table shows the possible impact of a one percentage point increase in the interest rate.

Impact of a One Percentage Point Increase in Interest Rate on the Cost of Capital of Publicly Owned Canadian Natural Gas Distributors*

	Increase in cost of capital ($ million)	Sales (millions of mcf)	Increase in average price ($/mcf)	Average price ($/mcf)
1981	0.8	182	.004	3.08
1982	1.7	186	.009	3.57
1983	2.5	185	.014	3.95
1984	3.5	207	.017	4.03
1985	4.7	216	.022	4.18

* All numbers are in current dollars. Average price and sales figures are estimated from forecasts by the various utilities. Investment estimates are proportional to sales of publicly owned natural gas distributors.

III NATURAL GAS PIPELINES

1 Background on Gas Pipelines

Corresponding to growing amounts of natural gas transported, the natural gas pipeline distance grew at an annual average rate of 3% over the 1972-81 period. With the extension of the transmission system to Montréal and then Québec City in 1982 and 1983, we expect a pause in the growth rate for the three or four coming years. The next sources of growth are likely to be the development of Sable Island field offshore Nova Scotia, the Vancouver Island project and/or Dome's LNG export plan and possibly some more export facilities towards the end of this decade. Also, future investment expenditures in this industry will be lower than in the recent past when it averaged $1 billion a year. Gas pipeline corporations are all investor-owned in Canada. Over the period 1978-81, equity represented around 40% of total capitalization. Long-term liabilities counted for 75% of total liabilities.

2 Rate-Setting in Gas Pipelines and the Role of Interest Rates

All pipeline corporations are regulated by the National Energy Board in Canada. Rates are determined in the way described above for investor-owned natural gas distributors. Rates must generate sufficient revenues to cover costs of service, including fixed capital costs, and a fair rate of return on equity. It is worth noting here that the NEB does not try to allocate costs of an expansion of the network to customers served by this expansion. As an example, if a new line is built for exports, all consumers of that company will be affected by those additional costs. This issue is currently under debate at the Board.

Using the same methodology as before (debt being refinanced over the coming 20 years, depreciation of assets over the next 25 years) and assuming investment expenditures of $1,200 million in 1982, $400 million in 1983, $450 million in 1984 and $500 million in 1985, we computed the impact of a one percentage point increase in interest rates for natural gas pipelines in Canada. The results are presented below.

Impact of a One Percentage Point Increase in Interest Rate on the Capital Costs of Gas Pipeline Corporations*

	Increase in cost of capital ($ million)	Sales (domestic + exports) (millions of mcf)	Increase in average price ($/mcf)	Average price ($/mcf)
1981	35	2,276	.015	3.08
1982	47	2,334	.020	3.57
1983	51	2,236	.023	3.95
1984	56	2,491	.023	4.03
1985	62	2,620	.024	4.18

* Sales are estimated from forecasts by the various utilities. Financial data are from Statistics Canada, 55-002.

IV CONCLUSIONS

Interest rate variations will affect costs and prices through the regulatory process. In that respect, interest rate levels (and capital costs) are an important component of rate levels for electricity and, to a lesser degree, for natural gas. The following tables present our (rough) estimates of the effect of a permanent one percentage point interest rate shock on the total cost of capital of Canadian electric and natural gas utilities.

Impact of a One Percentage Point Increase in Interest Rate on the Capital Costs of Canadian Electric Utilities

	Increase in cost of capital ($ million)	Total sales (billions of kwh)	Average price (cents/kwh)	Increase in average price* (%)
1982	104	364	2.7	1.07
1983	199	382	3.0	1.73
1984	284	400	3.2	2.20
1985	359	424	3.5	2.45
1986	429	439	3.6	2.71
1987	505	455	3.8	2.93
1988	589	471	4.0	3.13
1989	683	487	4.2	3.31
1990	794	504	4.5	3.53

* Gives the percentage change in the average price of electricity if cost changes feed directly into price changes.

Impact of a One Percentage Point Increase in Interest Rate on the Capital Costs of Canadian Natural Gas Utilities

	Increase in cost of capital ($ millions)	Total sales (millions of mcf)	Average price ($/mcf)	Increase in average price* (%)
1981	66	2,276	3.08	1.00
1982	83	2,334	3.57	1.01
1983	93	2,236	3.95	1.06
1984	105	2,491	4.03	1.04
1985	118	2,620	4.18	1.08

* Gives the percentage change in the average price of electricity if cost changes feed directly into price changes.

These numbers represent estimates of the direct impact on costs assuming that sales are not affected by such a change. However, sales might be lowered if cost increases translate into corresponding rate increases and/or if high (real) interest rates result in a significant slowdown in the economic activity. Given the large share of hydro and nuclear generating capacity in the Canadian electric power industry, lower sales will not result in a considerable reduction in operating costs and

capital expenditures in the short run, necessitating a larger average price to raise the revenue requirement. Because the fixed cost component is less important for natural gas utilities, this indirect effect would be much smaller.

Even if cost is considered the standard for revenue requirements of most energy-related utilities, there are many reasons why the relation between cost increases and rate changes will not be as stable as many people might think.[16] First, for most publicly owned utilities, financial criteria used to determine rates are no more than broad targets set by either the regulatory body or the utility, and around which expected values may fluctuate. Also, for publicly owned utilities, the rate of return on the "equity" component of their financing is ignored and consequently, retained earnings may become very low (even negative), no matter what is the economic situation in similar privately owned firms. For such utilities, increases in the interest rate may be translated into a lower return on equity rather than higher prices. Although the flexibility on the return on equity is not as important for privately owned utilities, high real rates of interest (and poor economic prospects) will not necessarily result in a higher opportunity cost of equity capital and then, in a higher granted rate of return and larger rate increases.

As well, there is some evidence that, despite their monopoly power on specific markets, competition among different energy sources helps to limit price increases in regulated utilities. For some utilities, higher capital costs could not be transmitted to prices without impairing future sources of growth. In such cases, higher uncontrollable costs were compensated by letting financial ratios deteriorate and/or by cutting controllable costs and/or by increasing their sales through new marketing efforts. Obviously, there are ultimate constraints for each utility and at some point cost increases will lead to price increases. Nevertheless, for many utilities (especially publicly owned utilities), large capital cost increases may not result in higher prices, at least in the short run. Finally, we would like to point out that provincial restraint programs have recently played an important role in limiting price increases in spite of large rises in the rate of interest.

In short, our major conclusion is that a higher nominal cost of capital will generally be transmitted into higher prices for electricity and natural gas through the regulatory process. However, competition among energy sources and political considerations will tend to displace the cost-price relationship over time or simply will not permit the price rise to take place, especially when real short-term interest rates are high as a result of tight monetary policy.

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16. More than one economist at the Research Department has failed to find a significant relation between electricity rates and some measures of capital costs. We think that the following reasons may explain why this is the case; the true relation must be very difficult to capture. In spite of those unsuccessful trials, the next step for us will be to use the information we obtained in this work to get some estimates of such relationship.

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